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ORIGINAL PAPER - PRODUCTION ENGINEERING

Investigation of reservoir temperature in a gas reservoir in Middle East: case study

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Abstract Having a good estimation of geothermal gradient and the reservoir temperature has a great impact on the methodological reservoir management in the entire reservoir life, from natural depletion phase up to draining the last portion of hydrocarbon by applying an appropriate EOR method. This issue could become crucial in a gas condensate reservoir management as the reservoir temperature has great influence on the time and amount of precipitated condensate in the reservoir and on the surface. It is usual to consider a constant reservoir temperature throughout the field. Also, encountering a constant geothermal gradient, with a similar fluid in a reservoir, is expected. During drilling campaign of two appraisal wells (one in the crest and other in the flank) of one of Middle East gas reservoir, it is aproximately found one geothermal gas gradient in both well; however, with some displacement in the wells. To find out a scientific justification for this phenomenon, a study was set out and results were presented in this paper. By using the analytical solution to unsteady-state conduction heat transfer for a cylinder with a radius of r_m and infinite length and the available temperature data from FBDSTs, the exact reservoir temperature at different depths is calculated. It is also shown that by using the analytical solution 'affected thermal well bore radius' can be estimated. The affected thermal well bore radius is defined as the radius that beyond it, formation rock is not affected by any downhole temperature variation. Based on the elaborated work, in addition to confirmation of having one geothermal gradient in the reservoir, it is found out that the 'affected thermal well bore radius' in wells is about 20–60 cm. Also by using the basic steady-state conduction heat transfer equation and assuming that the amount of transferred heat via layers of earth is constant, it is qualitatively shown that having different reservoir temperatures at constant depth throughout a giant deep-reservoir is normal and it should be accounted for the reservoir simulation.

Keywords Reservoir temperature · Geothermal gradient · Thermal radius · Different temperatures in one reservoir · Unsteady-state heat transfer in wells · Steady-state heat transfer in wells

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Introduction

Having a good estimation of geothermal gradient and the reservoir temperature has a great impact on the methodological reservoir management; however, as temperature is measured by wire line tools, its determination encounters the same difficulties as reservoir pressure measurement. In addition to the effect of reservoir temperature on rheology of circulation mud during drilling and on the quality analysis of petrophysics logs, it has a direct effect on determination of dew point pressure in gas reservoirs. Based on the dew point pressure, the amount of condensate in the reservoir and on the surface is forecasted. The amount of deposited condensate in the reservoir has a great influence on the relative permeability of reservoir rock and consequently will impact on the reservoir performance, especially on the potential of wells production in their life period. On the other hand, economy of development of a gas reservoir is totally dependent on the amount of produced condensate on the surface. Therefore, the reservoir temperature not only has technically a great influence on the field management method but also has a crucial effect on the final decision about the development of the reservoir.

Also, it is usual to consider one constant temperature throughout the entire reservoir; however, there are cases (as in the case which will be appraised) where it seems it is not the correct assumption. Based on the actual field data, both subjects are investigated in the following sections. To follow the confidentiality of the data, the following names are adopted: field of ‘A,’ reservoir of ‘B’ and the wells ‘C1,’ ‘C2’ and ‘C3.’

Available data

This study was carried out when three wells have been drilled in the field ‘A.’ The goal of drilling the wells was appraising the reservoir ‘B’. The well ‘C1’ didn’t reach the reservoir ‘B’ due to some mechanical issues.

In well ‘C2’ which is located on the crest, the total thickness of the target formation was drilled, and in addition to running ‘MDT,’ a series of full-bore drill stem tests (FBDSTs) have been performed in this well.

In well number ‘C3’ which is located in the flank of reservoir, the majority of target formation was drilled. In this well, the ‘MDT’ data are available, and also in addition to the FBDST, the production logging tool was run as one of the tests.

All available data were employed to determine the reservoir temperature and geothermal gradient. Figure 1 shows the temperature data obtained during running ‘MDT’ in the ‘C2’ and ‘C3’ wells. As it is shown, each set of temperatures (which are measured by different tools or different hole sizes) more or less follows a constant geothermal gradient equivalent to slope of 1.2–1.3 °F/(100 ft); however, there are two issues which are obvious in this figure:

1. The geothermal line is displaced in each well and even by changing the measuring tools or time of measurement, the line shows some changes:
    - In well ‘C3,’ the displacement of measured thermal slope lines obtained by two different thermometer gauges (quartz or strain) is around 2.5 °F.
    - The displacement of measured thermal slope lines in the two wells is about 16 °F, in average.
2. Deviation from average thermal slope is up to 25 °F.

To find out the reasons for these differences, a methodological study has been conducted and the results are presented in the following sections.

Investigations

The temperature measurements were made by two different temperature gauges: ‘quartz gauge’ and ‘strain gauge’. A consultancy is made with the ‘service company’ about the relative accuracy of the guages. It is assured that in the

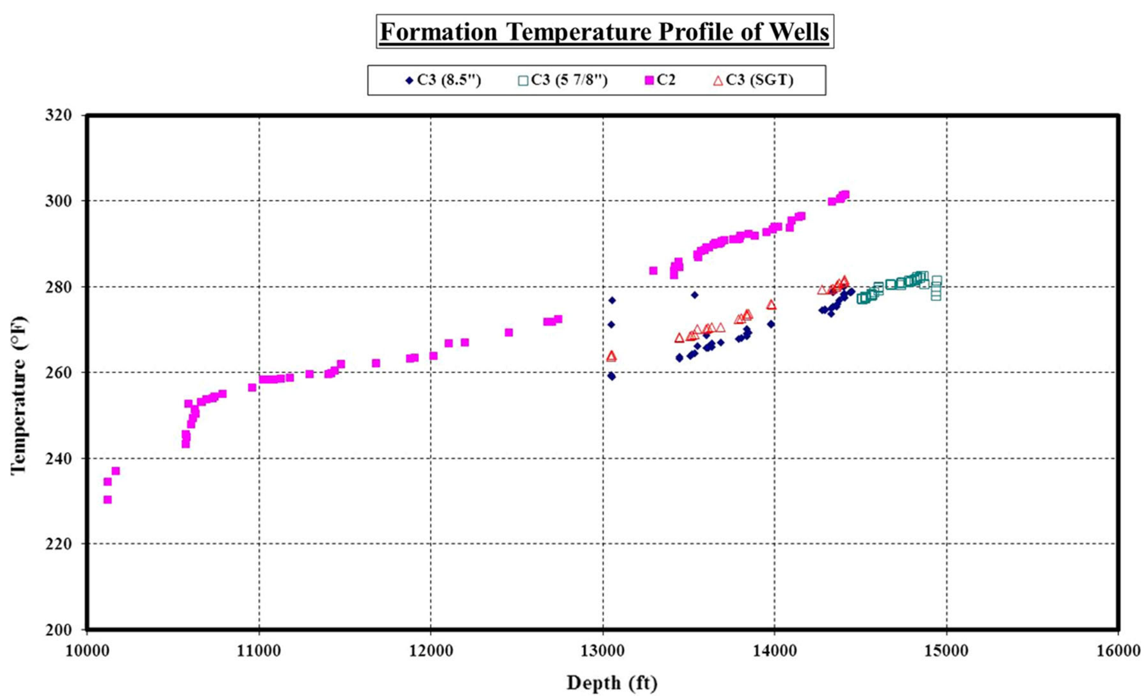

Fig. 1 General down-hole temperature profile

engineering accuracy the temperature measurements are confident and the measurements by the 'quartz gauge' are more confident than the 'strain' one. Also it is informed that the same phenomenon is observed in some other gas reservoirs.

Theoretical basis

Under static conditions (before any production/injection or circulation), the reservoir temperature is stabilized at constant temperature which follows the geothermal gradient. In a dynamic process such as production, injection or during drilling mud circulation, the down-hole temperature changes. These changes take place under two processes: convection and conduction. After a stop of production/injection operation, down-hole well temperature is readjusted to stabilize reservoir temperature. This readjustment also happens under the convection/conduction heat transfer processes. Considering both conduction and convection processes simultaneously in calculations would just complicate the computations. After start of shutting in the well, especially when using the down-hole valve, the flow of fluid sharply diminishes; so, we can ignore the effect of convection process on the temperature readjustment. Therefore, it is assumed that the process of returning the down-hole temperature to its static condition follows an unsteady-state heat conduction process.

The unsteady-state heat conduction process followed a partial differential equation similar to that of pressure changes:

$$\frac{\delta T}{\delta t} = \frac{\alpha}{r}\frac{\delta}{\delta r}\left(r\frac{\delta T}{\delta r}\right) \tag{1}$$

T, temperature; r, radius; t, time; α, thermal diffusivity: $\alpha = \frac{\kappa}{c\rho}$; κ, thermal conductivity, Btu/ft–h–°F or W/m–°C; c, specific heat at constant pressure, Btu/lb–°F or J/g–°C; ρ, density, lb/ft^3 or kg/m^3.

The solution of Eq. (1) for a cylinder with a radius of r_m and infinite length is reported as follows (the equation is adopted to be used for measured temperatures during a build-up pressure test) (McCabe et al. 1993):

$$\frac{T_F - T_t}{T_F - T_{ws}} = 0.692\mathrm{e}^{-5.78N_{Fo}} + 0.131\mathrm{e}^{-30.5N_{Fo}} + 0.0534\mathrm{e}^{-74.9N_{Fo}} + \ldots \tag{2}$$

$$N_{Fo} = \frac{\alpha t}{r_m^2} = \text{Fourier Number;}\ \ \mathrm{ft}^2/\mathrm{h}\ \text{or}\ \mathrm{m}^2/\mathrm{s} \tag{3}$$

T_F, formation temperature; T_t, shut-in bore hole temperature at time t; T_{ws}, shut-in bore hole temperature at time $t = 0$.

The numerical value of '$(T_F - T_t)/(T_F - T_{ws})$' is called the 'unaccomplished temperature change,' that is the fraction of the total possible temperature change that remains to be accomplished at any time.

By considering the following equations for density (ρ), specific heat (c) and thermal conductivity (κ), their numerical values have been estimated with a good accuracy:

$$\begin{aligned} c &= \phi c_\mathrm{F} + (1-\phi)c_\mathrm{R} \\ \rho &= \phi\rho_\mathrm{F} + (1-\phi)\rho_\mathrm{R} \\ \kappa &= \phi\kappa_\mathrm{F} + (1-\phi)\kappa_\mathrm{R} \end{aligned} \tag{4}$$

ϕ, porosity; c_F and c_R, specific heat of fluid and rock, respectively; ρ_F and ρ_R, density of fluid and rock, respectively; κ_F and κ_R, thermal conductivity of fluid and rock, respectively.

By using the average porosity of the reservoir and the available thermal properties (Somerton 1992), the average values of above parameters are estimated as follows:

$$\begin{aligned} &\rho = 2600\ \mathrm{kg/m^3}, \\ &c = 0.23\ \mathrm{cal/gr\ ^\circ k} = 0.23 \times 4.184 \times 10^3\ \mathrm{J/kg\ ^\circ k}, \\ &\kappa = 2.5\ \mathrm{w/m\ ^\circ k}, \\ &\therefore \alpha \cong 10^{-6}\ \mathrm{m^2/s} \end{aligned} \tag{5}$$

Equation (2) versus time is plotted (see Fig. 2). It is shown that if the temperature changes influence just around 30 cm (1 ft) of the well bore, 8 h after shutting in the well, the percent of 'unaccomplished temperature change' will be about 10 % of total changes. This means if the total change is 5°, after 8 h the amount of error in measured temperature will be about 0.5°. For 1 m radius, the amount of error after 10 h will be about 3°.

Also, by manipulation of Eq. (2), the following equation is obtained:

$$T_t = T_F - (T_F - T_{ws})E \tag{6}$$

E, right-hand side of Eq. (2).

It means that plotting the down-hole temperature versus 'E' [the RHS of Eq. (2)] will result in a straight line with negative slope and its value is the difference between reservoir temperature and the down-hole temperature at $t = 0$. Also the ordinate of line is the reservoir temperature. By comparing Eqs. (2) and (6), it can be seen that in Eq. (6), there are two unknowns: r_m and T_F. Therefore, for solving Eq. (6) a *trial-and-error* method should be used.

A few researchers (Kutasov and Eppelhaum 2005, 2010; Dowdle and Cobb 1975) suggested using the same method of Horner pressure build up for temperature build up. Their reason is the similarity between the Horner pressure build up and temperature build up. It is supposed that one solution to Eq. (1) for temperature build-up case would be the following equation:

$$T_{ws} = T_F - C\log\frac{t + \Delta t}{\Delta t} \tag{7}$$

As all theoretical aspects of this method are not fully elaborated, yet this method is just used as a check point, here.

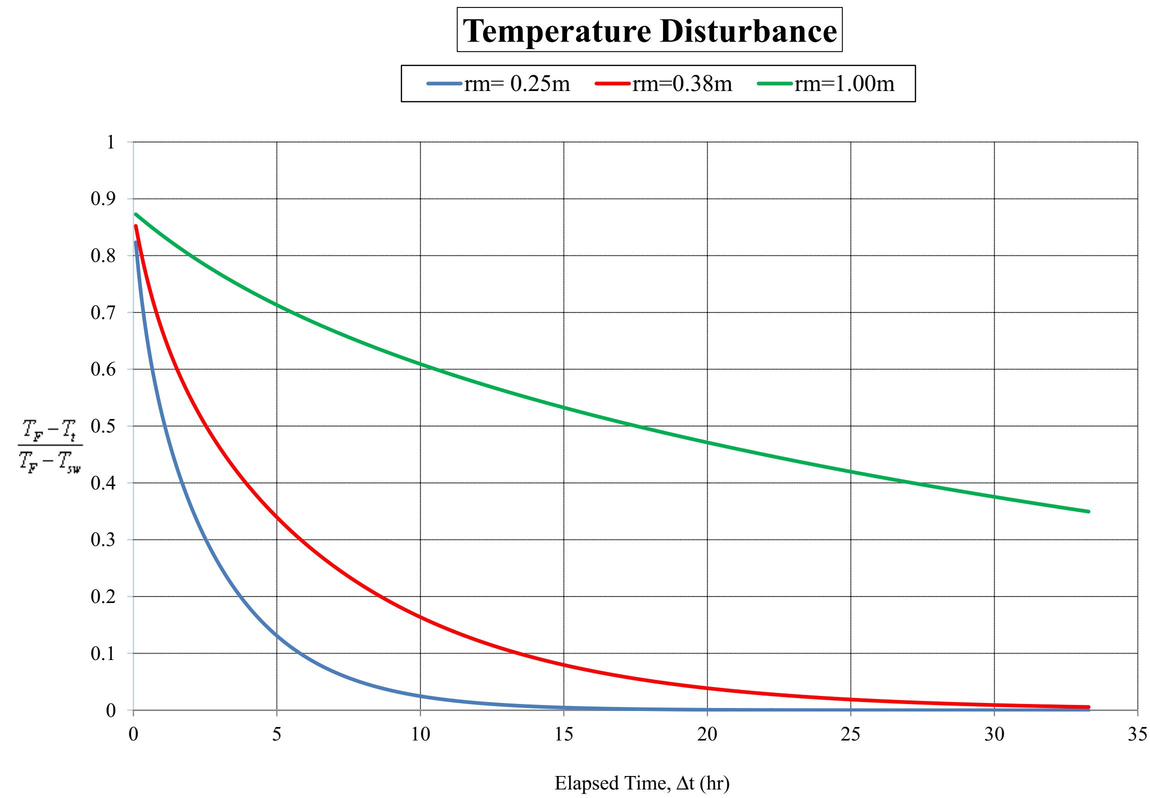

Fig. 2 Unaccomplished temperature change versus time and radius

A few computations

Based on the above theoretical basis, it is tried to obtain the temperature as close as possible to actual reservoir temperature from available temperature data recorded during FBDSTs in wells#C2 and C3.

Well number C3

Three FBDSTs are run in this well:

- FBDST-1 was in a $5\frac{7''}{8}$ open-hole section, with no flow (interval 4412–4570 m).
- FBDST-2 was in a 7″ liner (intervals 4200–4225 and 4365–4395 m).
- FBDST-3 was in a 7″ liner (intervals 4115–4133 and 4143–4159 m).

The bottom hole pressure and temperature variations (at the depth of 4352 m) are depicted in Fig. 3. In this test the well didn't flow; so, negligible temperature changes observed in the test. It seems that this temperature change can also be attributed to stabilization of geothermal gradient after stopping mud circulation. From this figure, the static down-hole temperature at the depth of 4352 m can be judged to be around 136.3 °C.

Temperature and pressure variation in FBDST-2 (at depth of 4018 m) is shown in Fig. 4. The well shut-in time in this test was enough large to be ensured that the well bore temperature reached an equilibrium with reservoir temperature. Thus, it can be concluded that the reservoir temperature at depth of 4018 m should be around 132.8 °C. Also, from temperature data of the main pressure build, the applicability of Eq. (6) has been investigated. In Eq. (6), there are two variables: time and r_m (the effected thermal radius). So, to draw a straight line to fit the data, a 'trial and error' method is used. Result is shown in Fig. 5. Based on the calculations, the affected thermal radius is about 32 cm, in this case.

For applying Eq. (6), one point should be kept in mind: This equation is derived by ignoring the convection heat transfer; however, due to 'wellbore storage' phenomenon, the effect of this type of heat transfer becomes more important, especially in early period of shutting the well. So, it is recommended to use the data points after fading away the 'wellbore storage' effect.

In Fig. 6, the FBDST-3 temperature and pressure data at depth of 4065 m of well C3 are plotted. By employing the Eq. (6) and applying the 'trial and error' method, the best straight line is fitted to the data. Result is shown in Fig. 7. Based on the calculations, the affected thermal radius is about 36.0 cm, in this case. The reservoir temperature is about 133.04 °C at depth of 4065 m.

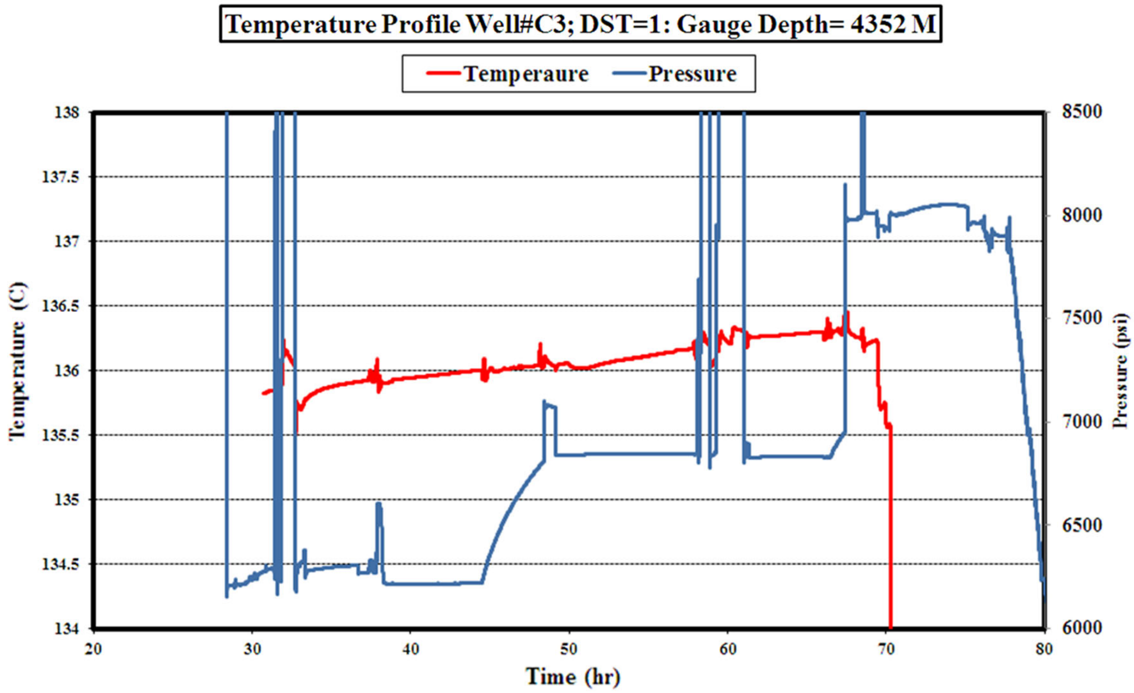

Fig. 3 Temperature profile of well#C3, FBDST#1

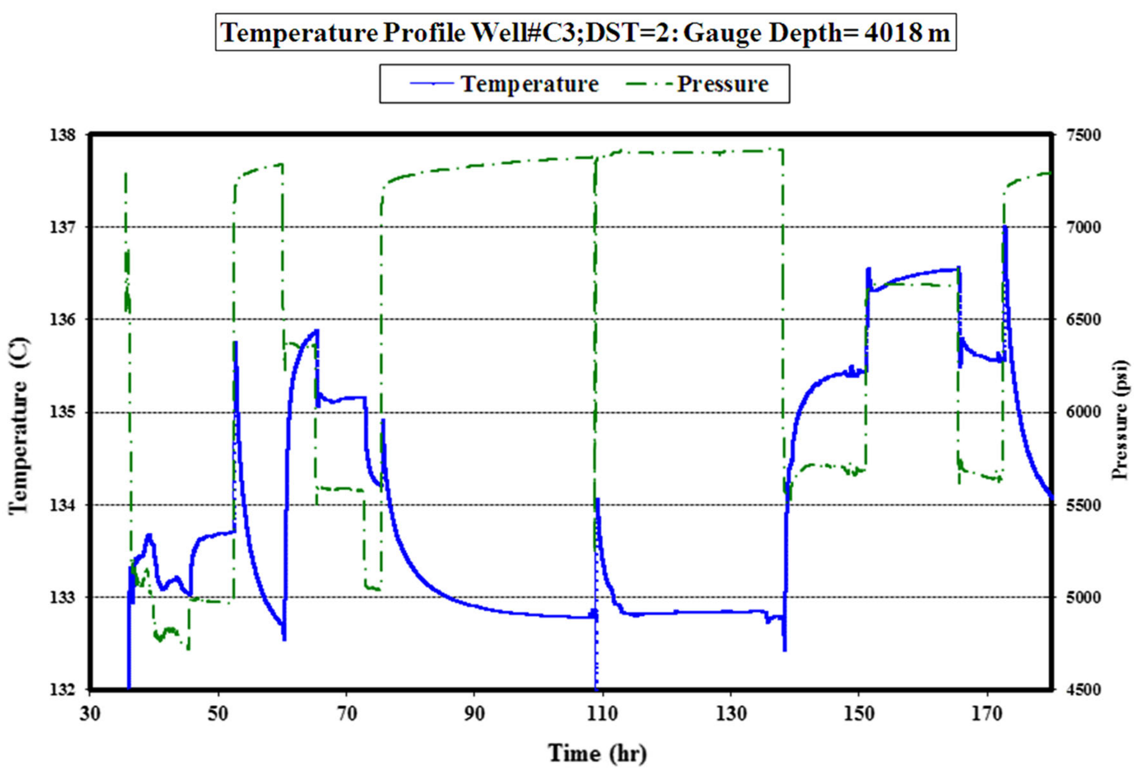

Fig. 4 Temperature profile of well#C3, FBDST#2

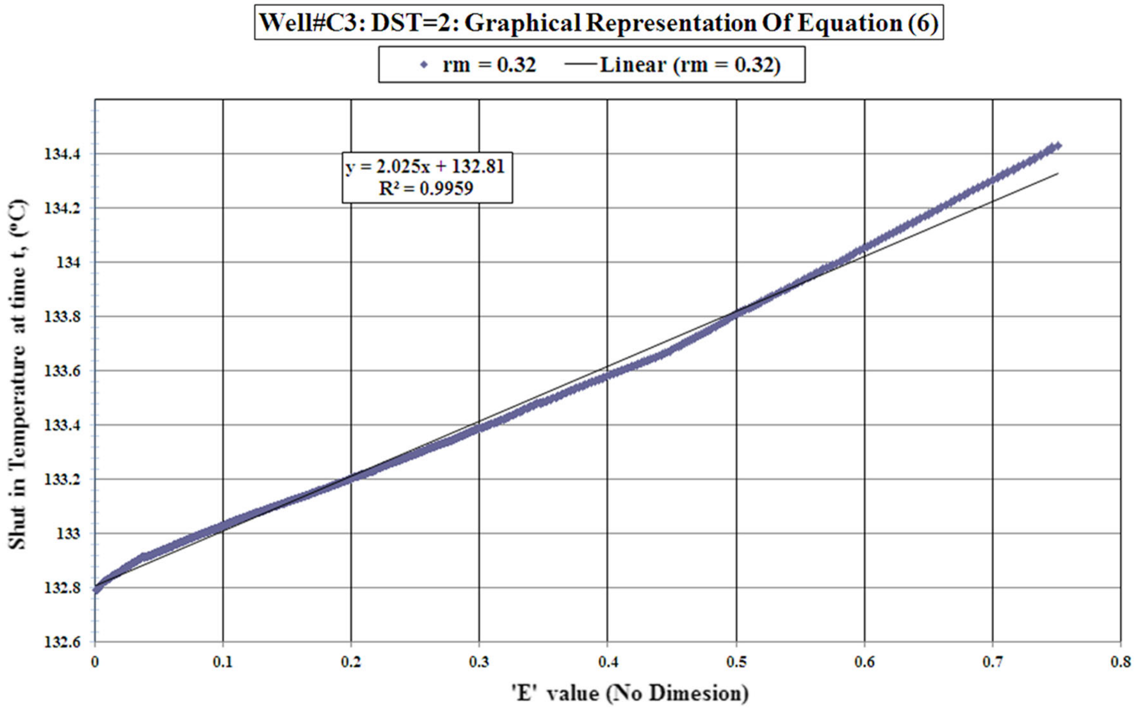

Fig. 5 Well#C3: DST = 2: graphical representation of Eq. (6)

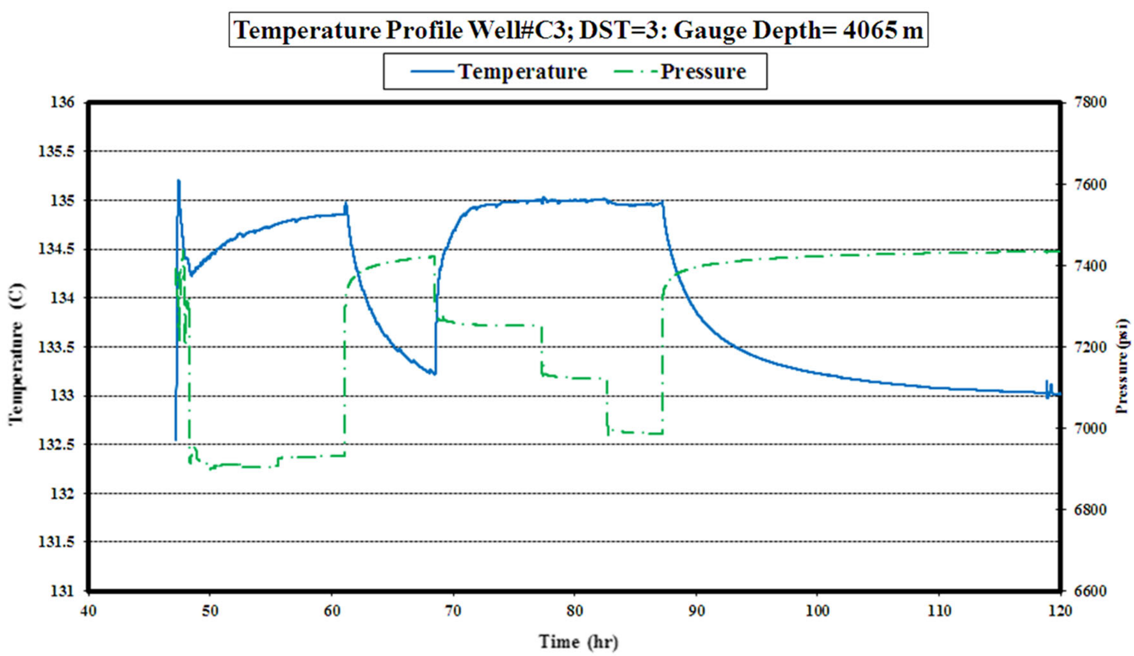

Fig. 6 Temperature profile of well#C3, FBDST#3

Well number C2

In summary, reservoir fluid (gas) in seven out of eleven FBDSTs flowed and reached to surface, in this well. Based on the investigations, similar to aforementioned studies for well number C3, reservoir temperature at the setting depth of gauge is obtained for each case. The results are presented in Table 1.

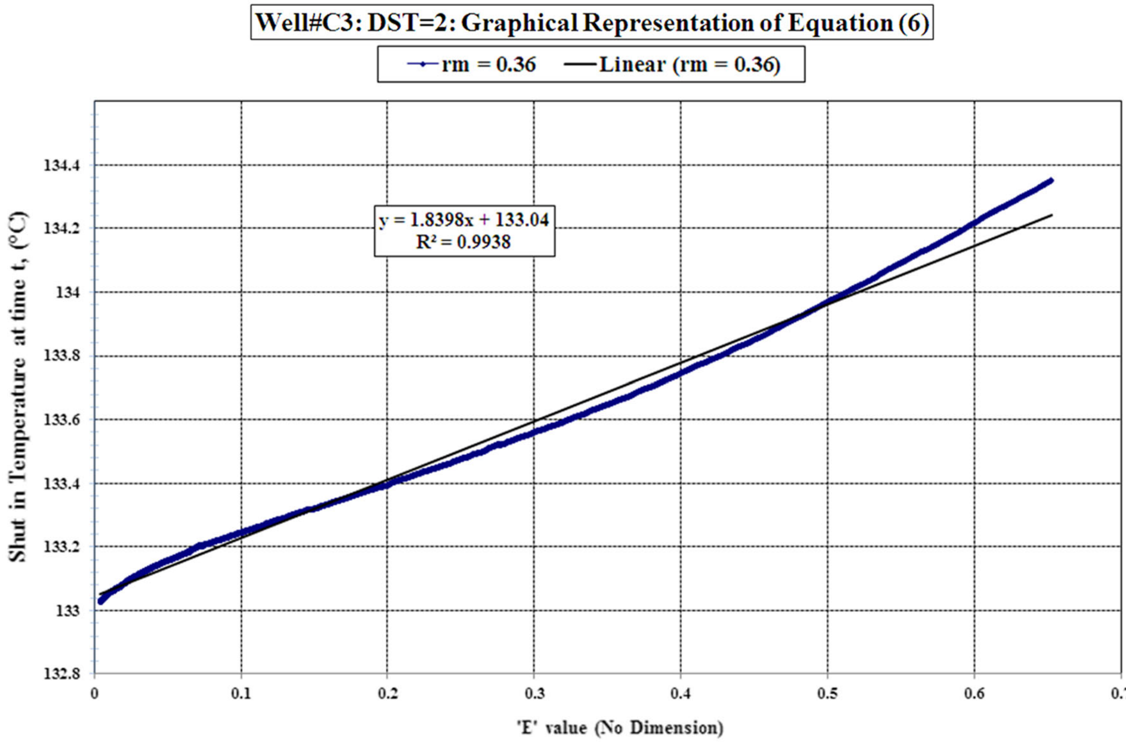

Fig. 7 Well#C3: DST = 2: graphical representation of Eq. (6)

Table 1 Estimated reservoir temperature by using available FBDSTs data of well number C2 and applying Eq. (6)

Test number	Depth (m)	r_m (cm)	Temperature (°C)
1	3940.6	–	137.6
6	3833.7	37	137.3
7	3673.2	65	133.5
8	3583	19	133.55
9	3408.3	41.5	127.8
10	3216.6	38	127.2
11	3184.5	28	127.4

Data filter out

Based on the aforementioned study, the data were again plotted; however, inferring a logical conclusion was difficult, yet. For better representation, the data of each well are separately plotted (see Fig. 8). By reviewing the available data of MDTs and taking a look on the geology of reservoir, by considering the following points, a basis could be acquired for applying further data filtration:

- Twenty meters of the top most of formation 'B' (which is under consideration) is not a reservoir section; so, the relevant data to this interval had been discarded.
- In the well number C3, the data of quartz and strain gauges did not correspond with each other in depths of deeper than 4125.3 m; so, the relevant data to this interval had also been neglected.

Figure 9 depicts the filtered-out data of wells, individually. The geothermal gradients in the two wells are almost equal, 1.25 and 1.14 °F/100 ft in wells C2 and C3, respectively. The two lines are not coinciding: Their movement is about 20 °F. It means that reservoir temperature in well number C2 is about 20 °F higher than in well number C3 at same depth. To investigate this issue, another study had been carried out and the result is presented in the following sections.

Reservoir temperature comparison of two wells

Steady-state conduction heat transfer is modeled with the following equation (Holman 2010; Jiji 2009):

$$q = kA\frac{\Delta T}{\Delta x} \tag{8}$$

k, thermal conductivity, Btu/ft–h–F or W/m–C; q, amount of heat, Btu/h or W; A, area of heat transfer, ft^2 or m^2; ΔT, temperature difference between two points, °F or °C; Δx, distance between two points, ft or m.

In case of geothermal gradient, the heat transfer is carried out between two very large (infinite) heat sources in conduction form. These sources can be considered as the earth surface and the 'earth mantel.' The heat is conducted

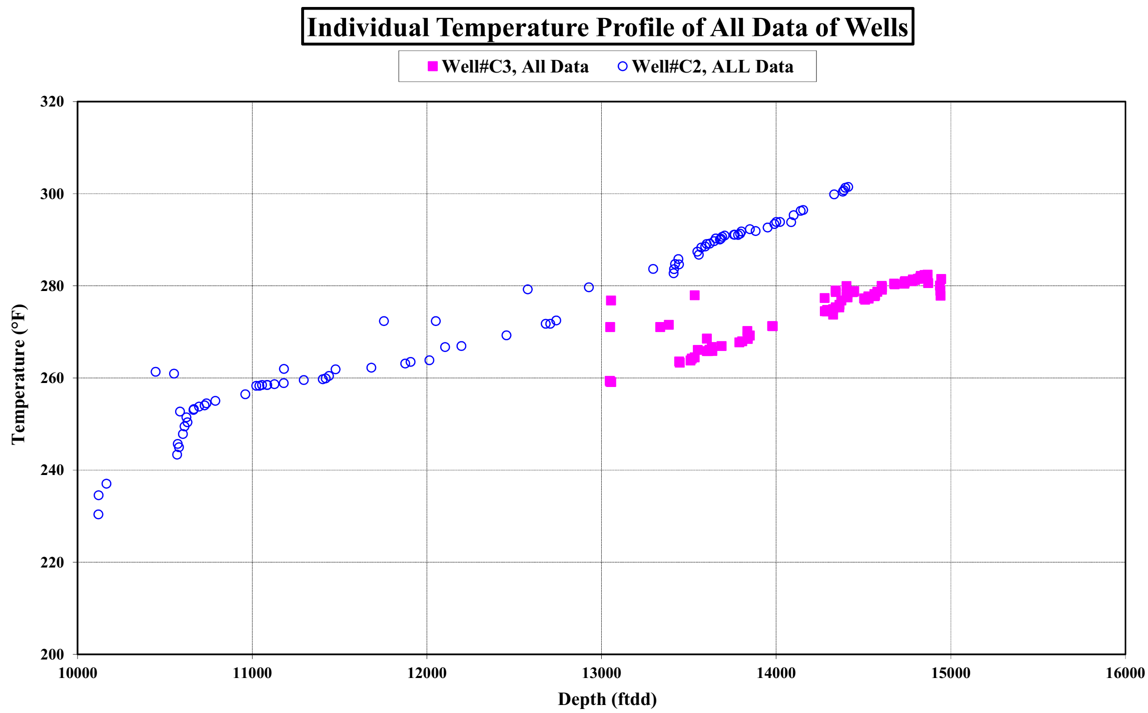

Fig. 8 Individual temperature profile of wells

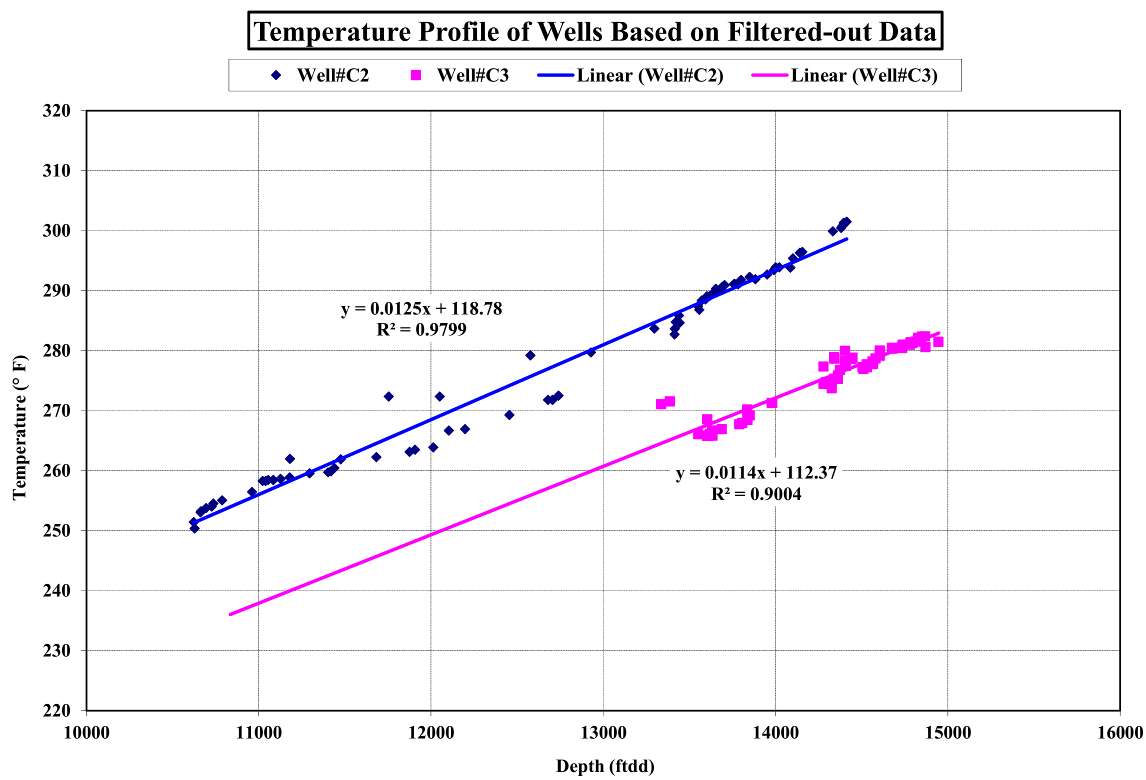

Fig. 9 Temperature profile of wells based on filtered-out data

via 'earth crust' layers in steady-state form. It is assumed that the earth layers act as conductors (or insulators) which are stacked in series (see Fig. 10). Therefore, the amount of heat conduction for all layers is constant and similar; however, the geothermal gradient factor for each layer differs from other layers which depends on the amount of

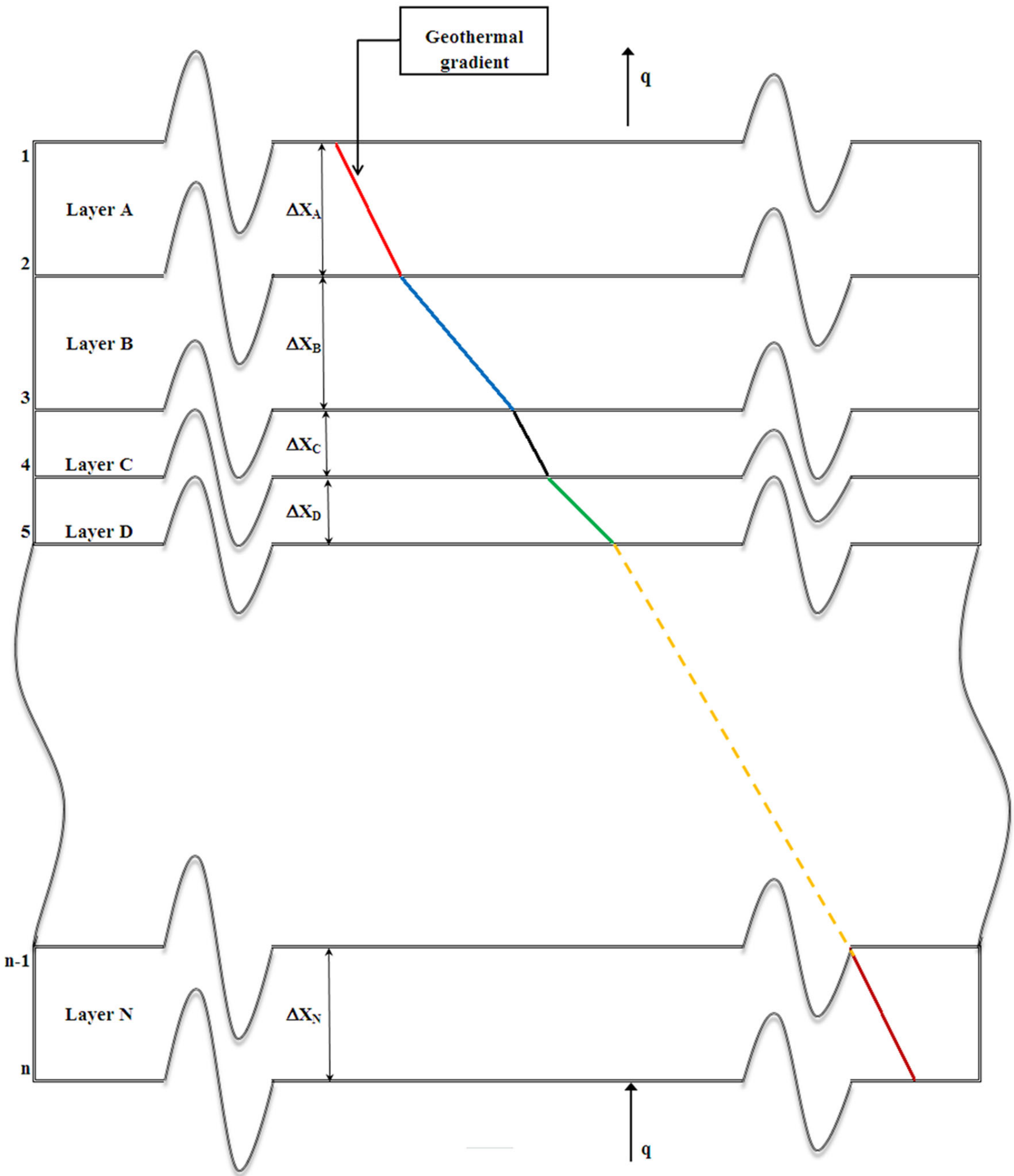

Fig. 10 Schematic diagram of steady-state heat conduction through earth layers

conductivity (or resistivity) of each layer. Thus, the following equations are valid for all layers.

$$q = k_A A \frac{T_1 - T_2}{\Delta x_A} = k_B A \frac{T_2 - T_3}{\Delta x_B} = k_C A \frac{T_3 - T_4}{\Delta x_C} = \cdots = k_N A \frac{T_{n-1} - T_n}{\Delta x_N} \quad (9)$$

The indices of A, B, C, … and N are names of earth layers; Δx_A, Δx_B, Δx_C, … and Δx_N are thickness of earth layers, and $(T_1 - T_2)$, $(T_2 - T_3)$, $(T_3 - T_4)$, … and $(T_{n-1} - T_n)$ are thermal potential of each layers.

Solving Eq. (9) simultaneously, the heat flow is written:

$$q = \frac{T_1 - T_n}{\Delta x_A / k_A A + \Delta x_B / k_B A + \Delta x_C / k_C A + \cdots + \Delta x_N / k_N A} \quad (10)$$

As it is mentioned, the two main sources of heat which impact on the earth temperature layers (earth crust and

Table 2 Thermal conductivities of some geological materials (Poelchau et al. 1997)

	Wm^{-1} K^{-1}	Source
Earth's crust	2.0–2.5	Kappelmeyer and Haenel (1974)
Rocks	1.2–5.9	Sass et al. (1971)
Sandstones	2.5	Clark (1966)
Shales	1.1–2.1	Clark (1966), Blackwell and Steele (1989)
Limestones	2.5–3	Clark (1966), Robertson (1979)
Water	0.6	At 20 °C
Oil	0.15	At 20 °C
Ice	2.1	Gretener (1981)
Air	0.025	Weast (1974) Handbook
Methane	0.033	Weast (1974) Handbook

atmosphere) can be considered as infinite acting sources; so, at two different points with a horizontal distance up to several kilometers in one field, the heat transfer (q) between earth layers would be constant and identical, from engineering calculation point of view. It means the amount of heat transfer between earth layers in location of well C2 can be considered to be equal to that in location of well C3. By considering the datum depth of about 14,000 ft, the following equations can be written for wells C2 and C3.

$$q = \frac{T_{14,000-\mathrm{C2}} - T_S}{\Delta x_{A-2}/k_{A-2}A + \Delta x_{B-2}/k_{B-2}A + \cdots + \Delta x_{N-2}/k_{N-2}A} \quad (11)$$

$$q = \frac{T_{14,000-\mathrm{C3}} - T_S}{\Delta x_{A-3}/k_{A-3}A + \Delta x_{B-3}/k_{B-3}A + \cdots + \Delta x_{N-3}/k_{N-3}A} \quad (12)$$

$\mathrm{T}_{14,000-\mathrm{C2}}$, $\mathrm{T}_{14,000-\mathrm{C3}}$ and T_S are temperatures of wells C2, C3 at depth of 14,000 ft and surface temperature, respectively.

At the same time, the T_S in Eqs. (11) and (12) are identical. On the other hand, the reservoir temperature in the well C3 is higher than well C2 at the same depth of 14000 ft, from aforementioned study. Therefore, the magnitude of numerator of Eq. (12) is larger that of Eq. (11). As it is assumed that 'q' is the same at the locations of both wells:

$$(\Delta x_{A-2}/k_{A-2} + \Delta x_{B-2}/k_{B-2} + \cdots + \Delta x_{N-2}/k_{N-2}) < (\Delta x_{A-3}/k_{A-3} + \Delta x_{B-3}/k_{B-2} + \cdots + \Delta x_{N-3}/k_{N-3}) \quad (13)$$

For the sake of simplicity and just qualitative investigation of subject, the vertical thickness in each well is divided into two reservoir and non-reservoir sections. By referring to well data, the reservoir top formation depths in wells C2 and C3 are 10,556 and 13,025 ft, respectively. By recalling the datum depth of 14,000 ft, Eq. (13) is modified as the following equation.

$$(14,000 - 10,556)/k_{\mathrm{reservoir}} + 10,556/k_{\mathrm{non-reservoir}} < (14,000 - 13,025)/k_{\mathrm{reservoir}} + 13,025/k_{\mathrm{non-reservoir}} \quad (14)$$

By some manipulation in Eq. (14), the following equation is deducible.

$$\therefore k_{\mathrm{reservoir}} > k_{\mathrm{non-reservoir}} \quad (15)$$

Equation (15) states that in the corresponding field, the conductivity of non-reservoir formations should be less than that of reservoir formation. As in this case, the reservoir rock is carbonate, and considering the non-reservoir rock composition which is mostly shale and by referring to references of rock thermal conductivity, for example Table 2 (Kutasov 1999), validity of Eq. (15) can simply be confirmed.

Therefore, the existence of an identical geothermal gradient of a reservoir is expectable; however, it is also expected to encounter a displacement in this geothermal gradient in the extent of reservoir.

Results and recommendations

Based on the presented materials, the following points can be drawn:

1. Pay attention when using the measured down-hole temperatures:
   - I. After any flow variation (injection or production), the well will experience down-hole pressure and temperature changes. Return of temperaure to its stablized condition (equilibrated to the reservoir temperature) takes several hours; although, pressure stabilization may take place very fast.
   - II. In the some down-hole tests, such as MDT, using two similar thermometers is recommended.
2. It seems that the 'affected thermal radius' in wells is about 20–60 cm. The affected thermal radius is defined as the radius that beyond it, formation rock is not affected by any down-hole temperature variation.
3. Reservoir geothermal gradient is more affected by texture of reservoir's rock and its fluid content; however, the reservoir temperature is more touched by texture of upper formations preceding the reservoir formation.
4. In giant deep-reservoirs, especially those with significant dips, in reservoir simulation, it should be kept in mind that the reservoir temperature in constant depth throughout the field is not constant.

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